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GOVERNMENT INCENTIVES IN CANADA'S PETROLEUM INDUSTRY

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CONTENTS

FIGURES AND TABLES.....iv

INTRODUCTION.....1

PART I A POLICY FRAMEWORK.....3

Constitutional Basis for Government Management of Natural Resources.....3

Government Objectives in the Management of Canada's Oil and Gas Resources.....5

The Present Tax Regime: A Brief Historical Development Since 1967.....8

PART II DESCRIPTION AND ANALYSIS.....15

Description of the Incentives in Canada's Oil and Gas Industry.....15

Impact on Revenue Distribution--Conventional Oil Production.....18

CONCLUSION.....33

APPENDIX A.....36

APPENDIX B.....37

APPENDIX C.....39

FIGURES

1 Comparison of Revenue Distributions from a Barrel of Oil With and Without Exploration and Development Expenditures.....24

2 Revenue Distribution of a Barrel of Oil With Varying Exploration Expenditure.....26

3 Revenue Distribution of a Barrel of Oil With Varying Development Expenditure.....27

TABLES

1 Incentives in the Canadian Oil and Gas Industry.....16

2 Government and Industry Shares on a Barrel of Conventional Oil Produced in Alberta: An Illustrative Example.....19

3 The Impact on Current Revenue Distribution of a per Unit Increase in Price, Operating Costs, Exploration Expenditure Development Expenditure, and Royalty.....28

INTRODUCTION

In order to achieve certain economic and political objectives the federal and certain provincial governments in Canada give incentives to Canada's oil and gas industry. The purpose of this paper is to describe these incentives, discussing the basis on which they are provided, their development over the 1970s, and how they interact to influence the distribution of revenue between industry and government on the sale of a barrel of oil.

The first part of the paper discusses some background material which we believe is helpful in understanding the development of government incentives in Canada's oil and gas industry. Included in this part is a discussion of the constitutional basis for government management of natural resources in Canada and the conflicts that can arise between levels of government when they exercise their separate jurisdictional powers. In addition, we discuss the changing tax position of the petroleum industry during the 1970s, a period in which dramatic changes were observed in both the price of energy and government taxation of the industry.

The second part of the paper describes the incentives currently before the industry and shows how they interact to influence the distribution of revenue between the industry and the provincial (Alberta) and federal governments.

PART I: A POLICY FRAMEWORK

Constitutional Basis for Government Management of Natural Resources

The British North America (BNA) Act of 1867 established the constitutional powers of the federal parliament and the provincial legislatures of Canada. The provinces were given exclusive powers in three areas related to the management of natural resources. First, the provinces have the power to make laws respecting the management and sale of public land which includes the management and sale of timber on this land. Secondly, they have exclusive jurisdiction over local works and undertakings but this authority does not extend to projects extending beyond the limits of the province such as railways, canals and pipelines. Thirdly, matters of a purely local nature are within the jurisdiction of the provinces. Also, the ownership and control of natural resources, including the granting of mineral rights and taxation is, with a few exceptions, left in the hands of the provincial legislatures.[1]

The federal parliament derives its jurisdiction over natural resources through its authority over property which is not owned by the provinces such as the national parks, Northwest Territories, Yukon, and the Arctic, as well as offshore territories designated as coming under federal jurisdiction. The federal parliament's jurisdiction in the area of trade and commerce is usually interpreted to extend to interprovincial and international transactions, thus giving the federal government powers to regulate interprovincial and international trade.[2] The taxing powers under the Act limit the provinces to direct taxation but extend to the federal parliament the authority of raising money with any mode of taxation--either direct or indirect.

The manner in which the powers and responsibilities have been delegated under the Act has opened the way for differing judicial interpretations and thus potential conflict and challenge. One area of concern has been the pricing of domestic oil. Under the BNA Act the ownership of natural resources is vested in the provinces. Affixed to the right of ownership are the implicit rights to make decisions concerning the development, production and pricing of the natural resources. The federal government's authority in the area of pricing arises from its jurisdiction over interprovincial and international trade. There is potential conflict if the federal government's pricing policy for oil sold outside Alberta produces a netback price in Alberta that does not conform to the interests of the Alberta government.

The area of oil and gas pricing overlaps both provincial and federal jurisdictions, as outlined in the BNA Act. The price of oil in Canada is currently set by negotiation between the federal government and producing provinces.

In some respects both the federal and provincial governments may be considered as competing to set a precedence. One level of government being the first to exercise its power in a specific area marks this area as lying within its respective judicial domain. Government competition to set a precedent in the 'grey areas' of the BNA Act can be expected to continue as each government level outlines its jurisdictional domain with a finer line.

Government Objectives in the Management of Canada's Oil and Gas Resources

Government ownership of natural resources carries with it a responsibility to manage the resource on behalf of the electorate. The general framework within which this responsibility is carried out is to rely mainly on private enterprise for the exploration, development, and production of these resources while retaining ownership by the Crown. Within Canada's natural resource industries, and in particular with respect to the petroleum and mining industries, there has evolved a complex series of regulations, fees, and taxes which serve to allocate exploration and production rights to private interests and give a return to the government for the sale of the resource.[3] Direct government involvement is also present as witnessed by the federal Crown corporation Petro-Canada and government investment in the Syncrude oil sands project.[4]

In allocating production rights to private industry, governments face the problem of presenting an incentive scheme that will meet government's objective and at the same time be attractive to the private industry. The relationship between government and the private petroleum industry can be described in terms of a 'principal-agent' relationship where the government (i.e., the principal) has the problem of designing an incentive scheme or fee schedule such that the industry (i.e., the agent) will operate in the principal's interest even though their objectives may differ. Complications in devising such a scheme arise from the fact that governments typically have a multitude of objectives some of which may conflict with the objectives of industry and the fact that in Canada the two levels of government, provincial and federal, each with powers to influence the behaviour of the industry, sometimes have different policy objectives. Private industry is frequently frustrated by a lack of firm direction in government policy which increases uncertainties and causes delays, often costly, in the private decision making process.

The basic objective that is usually sought by governments when it comes to managing natural resources is that the government should capture the rent due to the resource. Rent is that value remaining after all costs necessary to attract the labour, capital, and other inputs required to find, develop and produce the natural resource have been recovered. Rent is a surplus over and above that which is necessary to attract the necessary factors of production and thus its bestowal has no effect on the allocation of the factor inputs. In the exploitation of natural resources this rent is identified as a return to the one remaining factor of production, i.e., the natural resource, and is thus susceptible to capture by the resource owner.

While rent collection is an important objective, government involvement with the natural resource industry frequently extends into other areas. This further involvement reflects government concern with more general economic objectives such as price stability, full employment, equitable distribution of income, and economic growth as well as with the conservation and pollution aspects of natural resource development and production.[5] The energy industries have an important influence on economic growth, and both federal and provincial government policies reflect this fact.

A recent example of the kind of problems that can arise when the federal and provincial governments have different policy objectives concerns the non-deductibility of royalties in calculating federal income tax. Royalties are used by the producing provinces to collect rent due to the resource and are expressed as a percentage of the selling price. With the sharp increase in oil prices of 1973-74, the producing provinces increased their royalties to capture a larger share of the growing revenues to this industry. The federal government decided in 1974 to make royalties a non-deductible item in calculating tax since the higher royalties were seen as an erosion to the income tax base. The result was excessive taxation for the industry. The federal government's 'resource allowance' introduced in 1976 and the Alberta government's 'royalty rebate' also introduced in 1976 were the respective policies introduced by the two governments to compensate for the non-deductibility of royalties.[6]

Conflicts arise not only from differing objectives of the two senior levels of government as these apply to the petroleum industry, but also between the objectives of any one level of government. The most notable example of this is the federal government's objective of having more oil produced in Canada to increase our energy self-sufficiency side by side with the objective of protecting Canadian consumers from the higher world oil price. The present ceiling on Canada's domestic oil price and the subsidy to oil importers while insulating domestic consumers from the world price, does not promote the exploration and development of oil that would be promoted by a higher world oil price. Given the government's intention to raise the domestic oil price towards world levels throughout the 1980s, the protection from world oil prices afforded Canadian consumers will presumably be eroded.

Government policies had a major impact on Canada's petroleum industry during the 1960s and 1970s. Much of this impact revolved around changes in the tax treatment afforded this industry. These changes reflected two main developments. The first of these was the Royal Commission on Taxation (i.e., the Carter Commission) which called for major changes in the tax treatment of Canada's petroleum industry. The second was the rapid rise in world oil prices during the winter of 1973-74. Both developments played a major role in restructuring the tax burden on Canada's petroleum industry. The following section reviews how these two developments were instrumental in producing the tax system currently before the industry.

The Present Tax Regime: A Brief Historical Development Since 1967

The changes in taxation of the oil and gas industry during the 1970s were strongly influenced by two events: the publication of the Report of the Royal Commission on Taxation and the energy crisis of 1973-74.

A Royal Commission on Taxation (the Carter Commission) was appointed by the federal government in 1962 and its task was to undertake the first thorough examination of the underlying principles, logic, and philosophy of the Canadian tax system. Since the federal tax system had, up to that time, been developed as a result of many emergency measures due to wars or to other crises, it was thought that a critical examination was needed. It took several years before the Commission's six-volume report was released in early 1967. While all aspects of taxation were examined, and the findings and recommendations of the Commission were numerous and many of them detailed,[7] the most relevant area of taxation for our purpose was that of natural resources and particularly that of oil and gas production.

An important aspect of the taxation of extractive industries is the division of power to tax income between the federal government and the provinces, which has been discussed above. Traditionally, the federal government collected the corporate income tax and the provincial governments levied their direct income taxes on mining operations (collected for the provinces by the federal government). In addition, the provinces also levied royalties to reflect charge for the privilege of exploiting non-renewable natural resources.[8]

The specific federal and provincial fiscal incentives offered to the extractive industries prior to the appointment of the Royal Commission included the following: (i) qualifying corporations could immediately claim the costs of exploration and development as deductions from income from any source, with any portion of these costs not absorbed against current income carried forward indefinitely;

(ii) the income of all new mines was exempt from tax for the period of three years, which meant that together with the possibility of indefinitely carried forward capital and cost allowance or development costs, the three income tax free years could be prolonged by additional years; and (iii) qualifying operators of mines and of oil and gas wells could automatically claim a depletion allowance equal to one-third of taxable income arising from their extractive activities, which basically meant a one-third reduction in the effective rate of corporation income tax.

One of the Royal Commission's chief recommendations was that income be defined in a broader sense (including all accretions of economic wealth) and that the best and the most equitable way of taxation is through a system with low progressive tax rates applied to a broad tax base. As far as the extractive industries were concerned, the Royal Commission recommended a substantial reduction of the special tax treatment although it did not call for its overall elimination.

When the Report was released in February of 1967, it stirred a considerable amount of public discussion. The federal government first issued a White Paper entitled "Proposals for Tax Reform" in 1969, after which a new Income Tax Act was introduced in 1971. Although the new Act did not reduce the special treatment of the extractive industries by nearly as much as the Royal Commission had recommended, there were significant changes. Among them were the following two which directly affected the extractive industry. First, the automatic depletion allowance of one-third of taxable income was to terminate by the end of 1976 and be replaced by an 'earned' depletion whereby for each $3.00 spent on exploration or development an operator would earn the right to deduct $1.00 from his taxable income. This was a significant change designed to provide an investment incentive for the extractive industries. The second change was the elimination of the three-year tax holiday for new mines by 1973. It was to be replaced by a fast write-off of assets related to new mines or expansion of existing mines. In formulating the new tax laws, the federal government seems to have been particularly influenced by not only the risk, depletion, and 'catch-up' arguments referred to earlier, but also the contribution of the extractive industry to regional economic development.[9]

Shortly after the new tax regime came into effect, dramatic increases occurred in the price of oil on the world market. This resulted in difficulites in revenue sharing between the federal government and the provinces, especially in 1974 and 1975. In 1973, the year of the war in the Middle East and the oil embargo which followed, the average wellhead price of Canadian crude oil was $3.41 per barrel and the price of oil imported to eastern Canada was $3.67 per barrel.[10] Within a year the world price almost quadrupled and was still rising. The federal government reacted to this sharp increase in the world price of oil by instituting a two-price policy. To protect domestic consumers, the government legislated a domestic price below the world price and instituted an export tax equal to the difference for oil exported to the U.S. The domestic price was to be gradually increased to the world level. Concurrently, provincial royalties on oil and gas were increased. Shortly thereafter, the federal government announced that royalties would not be deductible as an expense in income tax calculations.

As both levels of government tried to appropriate as much as possible of the rising oil revenues, fears were expressed that the competition for oil revenues between the two levels of government would act as a disincentive which would seriously reduce exploration and development. Indeed, in spite of the announcement by Premier Lougheed in December 1974, of a change in Alberta royalty structure, 1975 statistics clearly show a considerable decline in survey activity and drilling in western Canada.[11]

The first sign of improvement in the relations between the two levels of government was the signing of the so-called 'Winnipeg Agreement' in February of 1975. This agreement established the federal government (15 percent) and the provincial governments of Alberta (10 percent) and Ontario (5 percent) as equity owners of the Syncrude project. The atmosphere of confrontation began changing to that of consultation. Subsequent policy development up to the present time has mainly involved two issues: increases of the domestic price of oil and the question of constitutional guarantees of ownership of natural resources for the provinces. Indeed, the question of ownership has played an important role in all recent federal-provincial constitution

conferences as a part of the much broader issue of repatriation and amendment of the Canadian Constitution.

Although the federal-provincial conferences in the recent past have not solved all the outstanding differences between the federal government and the petroleum-producing provinces, they at least have provided a suitable platform where the two parties could exchange opinions on energy and other matters.

As outlined earlier, in 1967 the Royal Commission recommended a substantial withdrawal of the special tax treatment of the extractive industry, and in fact the Income Tax Act of 1971 did include some of the recommendations. It is likely, however, that the numerous tax and royalty changes introduced during the period 1974-1978 have left the tax position of a majority of the oil and gas producers unchanged or provided them with increased incentives relative to their pre-1971 standing.[12]

Footnotes

[1]These exceptions include 'freehold' properties where mineral rights are held by private interests.

[2]An examination of the issue of Alberta natural gas exports to the United States shows how the jurisdictions of the federal and provincial governments interact. The ownership of resources is vested in the provinces (Crown mineral rights) who have the authority (section 109) to grant mineral rights to producers. In order that producers may sell their natural gas out of the province, they must submit an application to do so to the Alberta Energy Resources Conservation Board (ERCB). The ERCB's authority to accept such applications and conduct a hearing into the matter arises from provincial authority over matters of a local nature (section 92 (16)). Using a protection formula, the Board determines whether there is a gas surplus to Alberta's requirements. Once this surplus is quantified, the gas producers make applications to the National Energy Board (NEB) who conduct a hearing similar to that of the ERCB but using a protection formula for Canada. The NEB's authority to conduct such a hearing is derived from federal jurisdiction over trade and commerce (section 91 (2)). Since the applications to export gas involve the movement of a commodity outside provincial boundaries, the federal government has authority in this area of jurisdiction.

[3]For a review and economic evaluation of the regulations and taxes affecting management of the oil and gas industry in the province of Alberta, see M. Crommelin, P. Pearse, and A. Scott, "Management of Oil and Gas Resources in Alberta: An Economic Evaluation of Public Policy," Natural Resources Journal (April, 1978) pp. 337-389.

[4]Syncrude participation has since been diluted as the Alberta Energy Company (AEC) option was acquired in the summer of 1979. The current participation breakdown is:

Participants	% Ownership
Esso Resources Canada	25.0
Canada-Cities Service	17.6
Gulf Canada Resources	13.4
Petro-Canada Exploration	12.0
Alberta Energy Company	10.0
Alberta Government	8.0
Hudson Bay Oil and Gas	5.0
Petrofina Canada Exploration	5.0
PanCanadian Petroleum	4.0
	100.0

See Oilweek, September 17, 1979.

[5]Certainly within Alberta the provincial government's policies toward the energy industry reflect the goal of rent collection as well as economic growth, full employment, etc.

[6]These two policies are more fully described in the second part of this paper.

[7]For more details, see the Report itself or for example M. Bucovetsky and R. Bird, "Tax Reform in Canada: A Progress Report," National Tax Journal 25 (March, 1972) pp. 15-41, which also contains a good bibliography of other relevant literature.

[8]Royalty payments to provincial governments may be applied in two different ways. First, they may be as a flat-rate royalty. Alternatively, a royalty payment may be directly related to the wellhead price and the amount extracted, and the royalty then becomes a payment similar to tax. This has significant implications for the producer, for such royalty is in fact a variable cost, changing not only with production levels but also with the wellhead price. At present, most royalty payments are assessed on gross production and paid in equivalent wellhead value. See the royalty calculations in Appendix A.

[9]For further discussion, see Bucovetsky and Bird, p.35.

[10]Canada, Statistics Canada, The Crude Petroleum and Natural Gas Industry (Ottawa: Supply and Services), Catalogue No. 26-213, 1973.

[11]Relative to 1973, total survey activity decreased by 25 percent in 1974 and by 33 percent in 1975. The number of exploratory wells was also reduced. Relative to 1973, the number of wells drilled declined by 23 percent in 1974 and by 26 percent in 1975. The total metres drilled was down relative to 1973 by 18 percent in 1974 and by 20 percent in 1975. See Canadian Petroleum Association, Statistical Handbook (Calgary: Canadian Petroleum Association, 1978), Section I, Tables 4 and 6.

[12]Appendix C provides a chronology of the more relevant changes in federal and provincial taxation and royalties in the oil and gas industry as they have developed since 1974.

PART II: DESCRIPTION AND ANALYSIS

A Description of the Incentives in Canada's Oil and Gas Industry

Table 1 presents a summary outline of the main government incentives available to Canada's petroleum industry. Both levels of government, federal and provincial, may be viewed as offering the Canadian oil industry an incentive package, each package containing one or more incentive schemes each individually tailored to the respective levels of government's jurisdictional domain and their economic, social and political objectives. With this in mind, Table 1 has been organized vertically, presenting first the federal incentives and then the incentive packages of Alberta, Saskatchewan and British Columbia. The federal incentive package operates through the federal income tax. The incentive packages offered by the three producing provinces operate to reduce monies payable to the provincial governments.

There are basically two broad categories of incentives: earned and automatic. The resource allowance offered by the federal government is automatic in that there are no expenditure requirements imposed upon the industry. The depletion allowance and the exploration and development expensing programs are earned incentive schemes. Expenditures must be made before a producer would qualify to receive credit under these schemes.

There is a tendency to promote earned incentive schemes since these schemes can be more effectively directed towards specific activities within the industry. This tendency was illustrated when the federal government made depletion an earned allowance instead of an automatic deduction as it had been prior to 1971. All of the provincial incentive schemes shown in Table 1, with the notable exceptions of the Alberta Royalty Tax Credit and the provincial royalty rebate schemes, must be earned by the industry through qualified expenditures.

TABLE 1

INCENTIVES IN THE CANADIAN OIL AND GAS INDUSTRY[a]

	Incentive	Objectives	Application	Credit to:
FEDERAL	Resource Allowance	- to reduce the effective rate of federal tax (to compensate for non-deductibility of royalty in computing taxable income)	- 25% deduction from income on a defined basis	- deducted from taxable income
	Earned Depletion 1. Ordinary depletion	- to encourage the undertaking of risks inherent in resource exploration and development	1. lesser of 1/4 of resource profits or 33-1/3% earned depletion on conventional oil and gas operations + oil sands operations (including social assets and townsite facilities)	- deducted from taxable income
	2. Supplementary depletion		2. 50% earned depletion on enhanced recovery and oil sands equipment, up to 50% of total income after deducting ordinary depletion	
	3. Frontier depletion		3. 66-2/3% earned depletion on exploratory drilling costs in excess of $5 million per well, up to the remaining income after deducting all other depletion allowances	
	Exploration Expensing	- to allow recovery of most of the investment before taxes are paid on resource income	- 100% of defined Canadian exploration expenses	- deducted from taxable income
	Development Expensing		- 30% of defined Canadian development expenses, 100% for new mines which includes oil sands operations	- deducted from taxable income
ALBERTA	Exploratory Drilling Incentive System	- stimulate exploratory drilling activity - accelerate discovery of petroleum reserves - stimulation of rural economies	- certified drilling program earns credit according to schedule outlined in regulations	- lease rentals, penalties, royalties, provincial taxes
	Geophysical Incentive Program	- stimulate level of geophysical activity - retain nucleus of skilled geophysical personnel in Alberta	- certified geophysical program earns credit according to formula	- lease rentals, penalties, royalties, provincial taxes
	Royalty Tax Credit	- increase industry cash flow by reducing royalties payable	- lesser of (1) 25% of corporations attributed Alberta royalty income, or (2) $1,000,000	- credit against total tax payable
	Alberta Royalty Rebate	- increase industry cash flow by reducing provincial tax payable (to compensate for royalty non-deductibility)	- rebate calculated using formula. If Alberta tax payable is less than this amount take tax payable as rebate	- credit against provincial tax payable
SASKATCHEWAN	Approved Expenditure Grants	- increase investment in oil and gas industry	- credit calculated as 75% of approved expenditures	- financial assistance paid to firm out of Saskatchewan Heritage Fund
	Certified Exploratory Well Grants	- increase exploratory drilling activity	- credits calculated with formula	
	Saskatchewan Royalty Rebate	- increase industry cash flow by reducing royalties payable	- difference between provincial tax payable and provincial tax due if royalties were deductible but not resource allowance	- credit against provincial tax payable
B.C.	B.C. Royalty & Deemed Income Rebate	- increase industry cash flow by reducing royalties payable	- difference between provincial tax payable and provincial tax due if royalties were deductible but not resource allowance	- credit against provincial tax payable

URCES: (1) Canadian Taxation of Mining Income, Holland, Kemp, Ernst & Ernst, CCH Canadian Limited, 1978.
(2) Canadian Income Taxation of Oil and Gas, Canadian Petroleum Tax Society, April 10, 1979.
(3) Provincial Tax and Royalty Development Oil and Gas Resource Operations, Cochrane, Twenty-seventh Tax Conference, 1975.

) this table we have listed the incentives provided by the federal government and the three western provincial governments since it is
rta, Saskatchewan and British Columbia that essentially all of the oil and gas activity is centred. The exploration activity off
dland's coast earns 'frontier depletion'.

Not shown in Table 1 are the royalty schemes of the provinces, but it should be noted that they have also been designed to provide an incentive to the industry. Alberta, Saskatchewan and British Columbia royalty schemes distinguish between 'old' and 'new' oil, the demarcation date being January 1, 1974. The royalty rates for new oil are lower than those for old, which represents a formal recognition by government of the rising costs in this industry, and thus provides an incentive to producers in their search for new reserves. A recent decision by the Alberta legislature reduced the royalty rate for low (less than 1,200 barrels a month) producing wells. Effectively, this decision reduces the costs to the operator and thus encourages the extraction of oil from marginal wells rather than shutting them down. The Saskatchewan royalty scheme incorporates an 'area adjustment-modifier' which is another variable designed in recognition of the costs faced by the petroleum industry. This variable is designed to reduce the royalty rate on production from high cost areas; reflecting more difficult terrain and stratigraphies.

The incentives offered to oil sands production in Alberta include the world price for oil, a supplementary depletion allowance on top of ordinary depletion, 100 percent development expensing which includes social infrastructure investment and the right to deduct royalties in calculating income tax. Other incentives offered are negotiated separately between the government and operator of each plant.

Impact on Revenue Distribution
From Conventional Oil Production

The incentives in Canada's oil and gas industry have the effect of improving the cash position of firms in the industry and thereby the rate of return that can be realized on investment in either exploration or development. To illustrate how the incentives influence the industry's cash position we show, in Table 2, the calculation of industry and government shares on the revenue from a barrel of oil given certain assumptions.

The assumptions regarding expenditures per barrel, which are listed in a note to the table, represent gross industry averages and thus do not reflect the situation for any one firm. The $2.50/bbl and $1.50/bbl shown respectively for exploration and development are arrived at by dividing current industry expenditures in Alberta by current conventional output in Alberta. Such expenditures are deductible items in arriving at income tax payable on a barrel of oil. We refer to expenditures per barrel rather than cost per barrel, since the exploration and development expenditures of $2.50 and $1.50 respectively do not indicate development and exploration costs per barrel. The exploration and development cost of today's barrel of oil can only be calculated by summing past exploration and development expenditures that were instrumental in producing today's barrel of oil.[1]

Today's exploration and development expenditures yield future barrels of oil.[2] To calculate current exploration and development costs on a barrel of oil we need to forecast the output made possible by such expenditures and relate this future output to today's investment.[3] Thus the exploration and development expenditures shown in Table 2 are not the investment costs required to produce a barrel of oil but current investment expenditure directed towards a future return divided by current output.

TABLE 2

GOVERNMENT AND INDUSTRY SHARES ON A BARREL OF CONVENTIONAL OIL PRODUCED IN ALBERTA: AN ILLUSTRATIVE EXAMPLE ($/bbl)

Tax Calculation		
Gross revenue		14.75
Operating costs		(1.25)
Capital cost allowance (30%)[a]		(0.10)
Resource profits		13.40
Resource allowance (25%)		(3.35)
Exploration expense (100% deductible)		(2.50)
Development expense (30% deductible declining balance)		(0.45)
		7.10
Earned depletion (33-1/3%)[b]		(1.33)
Taxable income		5.77
Federal corporate income tax (36%)		(2.08)
Provincial tax - before rebate (11%)	0.63	
Rebate calculation:		
Royalty (41%)	6.05	
Lease rentals	0.10	
Non-deductible	6.15	
Resource allowance	(3.35)	
Net	2.80	
Rebate (11%)	(0.31)	
Net provincial tax		(0.32)

Industry Cash Flow		
Gross revenue		14.75
Operating costs		(1.25)
Royalty		(6.05)
Lease rentals		(0.10)
Federal tax		(2.08)
Net provincial tax		(0.32)
Industry cash flow		4.95

Distribution		
Industry	4.95	34
Provincial government[c]	6.47	44
Federal government	2.08	14
Operating costs	1.25	8
Total revenue	14.75	100

NOTES: Assumptions:

Price	- $14.75/bbl
Operating costs	- $1.25/bbl
Capital cost allowance	- $0.10/bbl
Lease rentals	- $0.10/bbl
Exploration expenditure	- $2.50/bbl
Development expenditure	- $1.50/bbl

[a]The capital cost allowance is 30 percent of the eligible base defined in the Canadian tax guide (i.e., building, machinery, equipment, etc.).

[b]Earned depletion is the lesser of 25 percent of 7.10 or 33-1/3 percent total exploration and development expenditure.

[c]The Alberta government revenue is the sum of the royalty, lease rental and tax (i.e., 6.05 + 0.10 + 0.32)

It is assumed that the representative producer to which Table 2 applies operates only in Alberta, the province which accounts for about 80 percent of Canada's oil and gas production.[4] The operating, development, and exploration expenditures per barrel are calculated using data from the Canadian Petroleum Association (CPA) statistical handbook.[5] The lease rental of $0.10 per barrel reflects the Alberta government's expected revenue from lease rentals for 1979.[6] The capital cost allowance (CCA) of $0.10 per barrel is the same as that assumed in the Federal Department of Energy, Mines and Resources' report, 'A Summary of Royalty, Taxation and Incentive Schemes Applicable to Oil and Gas'.[7]

As already noted, the expenditure assumptions shown in Table 2 are averages for the Alberta petroleum industry; they are not meant to reflect the situation for any one firm. The actual costs for firms in the industry vary over a wide range reflecting various geological and economic factors. For example, the operating costs per barrel will be higher than $1.25 for old producing wells whose output has significantly declined due to resource exhaustion. Exploration expenditures per barrel for any particular firm depend upon that firm's current output and exploration expenditure, both of which vary significantly between firms.

The price of oil and the federal and provincial tax rates shown in Table 2 are actual early 1980 values. The royalty of 41 percent is the average royalty paid in 1978 on conventional oil produced in Alberta.[8] As already discussed, the Alberta government levies a lower royalty on oil discovered since 1974 (i.e., 'new' oil). A higher royalty is applied on oil discovered before this date ('old' oil). The royalty is expressed as a certain percentage of production and is partial payment to the Crown for the natural resource. The remaining payments are bonus payments and lease rentals.[9]

Referring specifically to the calculations shown in Table 2, the federal and provincial income tax portions of the $14.75 per barrel selling price are $2.08 and $0.32 respectively. To calculate taxable income, operating costs and capital cost allowance are first subtracted from the selling price. The remaining revenue is termed 'resource

profits' which is the base on which the federal government applies the resource allowance. The resource allowance is the federal government's concession to the industry for making royalty and lease rentals non-deductible in calculating federal income tax. Subtracting the resource allowance, 100 percent of exploration expenditures ($2.50) and 30 percent of the development expenditures ($0.45) from resource profits leaves us with $7.10. Earned depletion is calculated next and in our example this is the lesser of 25 percent of $7.10 or 33-1/3 percent of total exploration and development expenditures. Earned depletion of $1.33 (33-1/3 percent of $4.00) is subtracted from the $7.10 to arrive at taxable income of $5.77. The federal corporate income tax is a straight 36 percent of taxable income. The Alberta provincial tax rate is 11 percent less a tax rebate. This tax rebate is given to the producer in recognition of the fact that royalty and lease rentals are no longer tax deductible. The sum of these non-deductible items is $6.15 in our example. The federal government's resource allowance of $3.35 is then subtracted leaving $2.80 as the base upon which the provincial government applies its tax rebate. The rebate is 11 percent of $2.80 or $0.29. The province's net income tax on a barrel of oil thus works out to be $0.32 ($0.63 - $0.31).

The rest of the calculations shown in the table are very easy to follow. The industry's cash flow is simply the selling price minus operating costs and the sum of the revenues collected by both governments. The average cash flow to the industry on a barrel of conventional oil produced in Alberta is $4.95 which accounts for 34 percent of the selling price. The Alberta government's share is 44 percent, the federal government's share is 14 percent, and operating costs account for the remaining 8 percent.[10]

The distribution of revenue generated by the Canadian oil and gas industry as opposed to just the conventional Alberta industry would probably involve a lower share for the federal government and a higher share for the industry, than that presented above. Exploration expenditures in Canada's frontier (Arctic and offshore) earn the 'frontier exploration allowance' which is a depletion allowance on top of the normal depletion shown in Table 2.[11] According to information

made available by the Federal Department of Energy, Mines and Resources, the distribution on net operating revenue (price minus operating costs) for the Canadian industry is 41.5 percent industry. 48.6 percent provincial governments (mainly Alberta), and 10 percent federal government.[12]

In Table 2 no consideration has been given to the Alberta government's 'exploratory drilling incentive system' introduced in 1972 and the 'geophysical incentive program' introduced in 1975. Through appropriate exploration drilling and geophysical activity a producer can receive credits towards monies payable to the Alberta government in the form of royalties, lease rentals, and taxes. In 1977 total credits under these two programs amounted to $87 million or approximately $0.10 per barrel (oil equivalent).[13] The distribution of revenue shown in Table 2 would probably change very little if we included the effects of Alberta's exploration and geophysical program. Subtracting $0.10 from Alberta's share and adding $0.10 to industry's share would change the respective proportions by about 1 percent. With increased exploration and geophysical activity, however, the value of the credit can be expected to grow.

The industry cash flow ($4.95/bbl) is before any allowance is made for <u>past</u> exploration and development investment required to find and develop the reserves from which the present barrel is produced. The net revenue that is attributable to past exploration and development expenditures is not $4.95 since this amount includes a certain amount of tax subsidy due to current exploration and development expenditures and thus cannot totally be considered as a return to past investments. The net revenue attributable to past exploration and development expenditures is $4.95 minus the extra cash flow made available to industry because of current exploration and development expenditures. The total exploration and development expenditure of $4.00 per barrel (shown in Table 2) makes current taxes less than otherwise, due to the depletion and expensing provisions. In other words, if we ask the question of how much is the industry earning on past investment in exploration and development, we need to look at the industry's cash flow excluding <u>current</u> exploration and development expenditures which relate to future production.

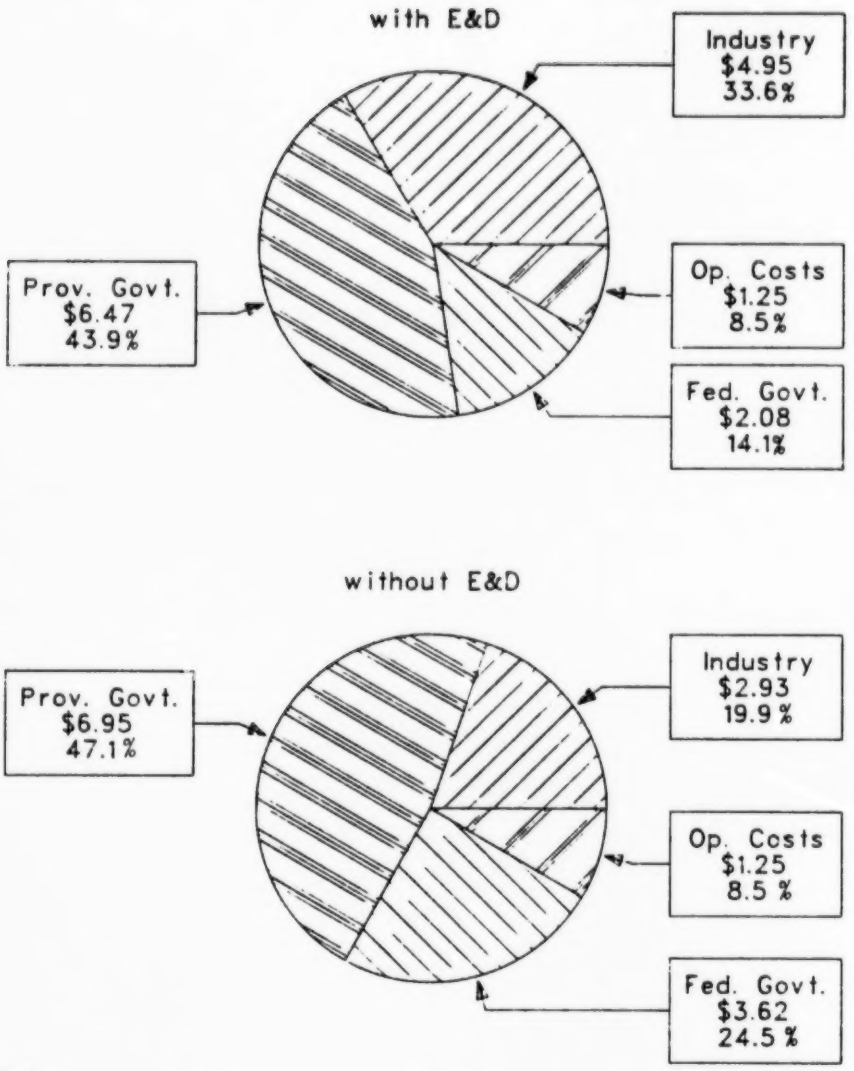
Figure 1 compares the distribution of the revenue from a barrel of oil with and without the exploration and development expenditures of $2.50 and $1.50 respectively. The distribution with exploration and development expenditures is simply the results reproduced from Table 2.

When exploration and development expenditures are dropped, the industry cash flow becomes $2.93 which is about $2.00 less than the case with exploration and development expenditures. The $2.93 is the industry's return on past investment. The provincial government's share becomes $6.95, up by $0.48. The federal government's share undergoes the largest increase, going from $2.08 with exploration and development expenditure to $3.62 without exploration and development expenditure. These results are dependent on the cost assumptions made in Table 2.

According to our analysis, an expenditure of $2.50 on exploration and $1.50 on development (all in Alberta) decreases corporate tax by about $2.00. This tax relief comes mainly from the federal government which gives up $1.54 per barrel in tax revenue. The provincial government gives up $0.48 per barrel in tax revenue.[14]

As mentioned above, the cash flow that would be relevant in calculating industry return on past investment is $2.93. On average, the industry is earning $2.93 on each barrel of conventional oil produced in Alberta, after payment of operating costs, taxes and royalties. If along with each barrel produced today the industry spends $2.50 on exploration and $1.50 on development, the resulting tax relief causes industry cash flow to increase from $2.93 to $4.95. It is important to note that it is not the $4.95 that is currently available for re-investment but rather $2.93 generated internally from past investment plus whatever investment funds can be attracted into the industry. The fact that investment expenditures (exploration and development) earn tax relief is an additional incentive for the attraction of investment into this industry.

Bonus payments to the Alberta government for the right to explore and produce are not included as part of the Alberta revenue shown in Table 2. In calculating income tax such payments are considered part of development expenditures and written off on a 30



Note:
The same assumptions used in Table 2 underlie the calculations of this figure: exploration expenditures of $2.50 per barrel and development expenditures of $1.50 per barrel.

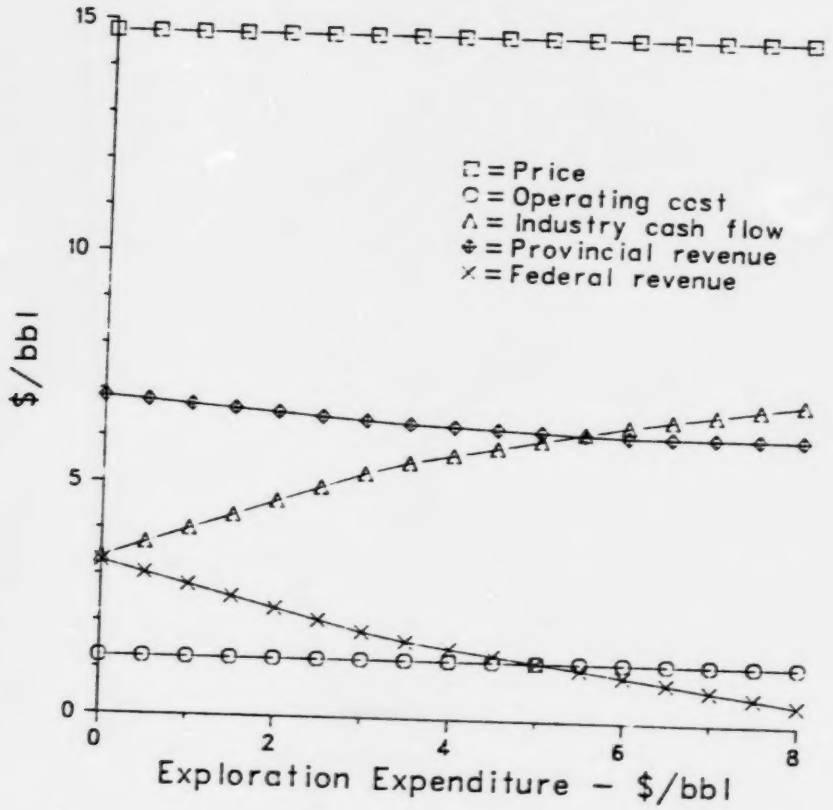
FIGURE 1: Comparison of Revenue Distributions from a Barrel of Oil With and Without Exploration and Development Expenditures (Price = $14.75/bbl).

percent declining balance basis. The development expenditure of $1.50 per barrel includes 'bonus' (or land acquisition) payments to the Alberta government. These payments are not included, however, in the revenue to the Alberta government since we are only showing the distribution of revenue from current production. Bonus payments are rightfully charged against future output. If we were considering the net return to the industry and to the Alberta government from the exploration for oil and gas reserves, we would have to calculate industry's return on investment and the Alberta government's total return from selling the resource.

We now turn to an examination of how sensitive the revenue shares are to a change in either exploration or development expenditures. Figures 2 and 3 illustrate the results of this analysis. The same assumptions that underlie Table 2 are assumed for Figures 2 and 3. In particular, only the 'ordinary depletion' of 33-1/3 percent is applied to the exploration and development expenditure. We remind the reader again that we are only showing how current cash flow is distributed given a certain amount of current investment expenditure; we are not showing the future cash flow or return that these expenditures make possible.

The increase in industry cash flow shown in the figures is primarily at the expense of federal tax revenue. As can be seen from referring back to Table 2, the Alberta government's main source of revenue is the royalty with lease rentals and income tax being relatively minor on a per barrel basis. The federal government's revenue comes from the corporate income tax where the important federal incentives involving expensing and earned depletion apply.[15]

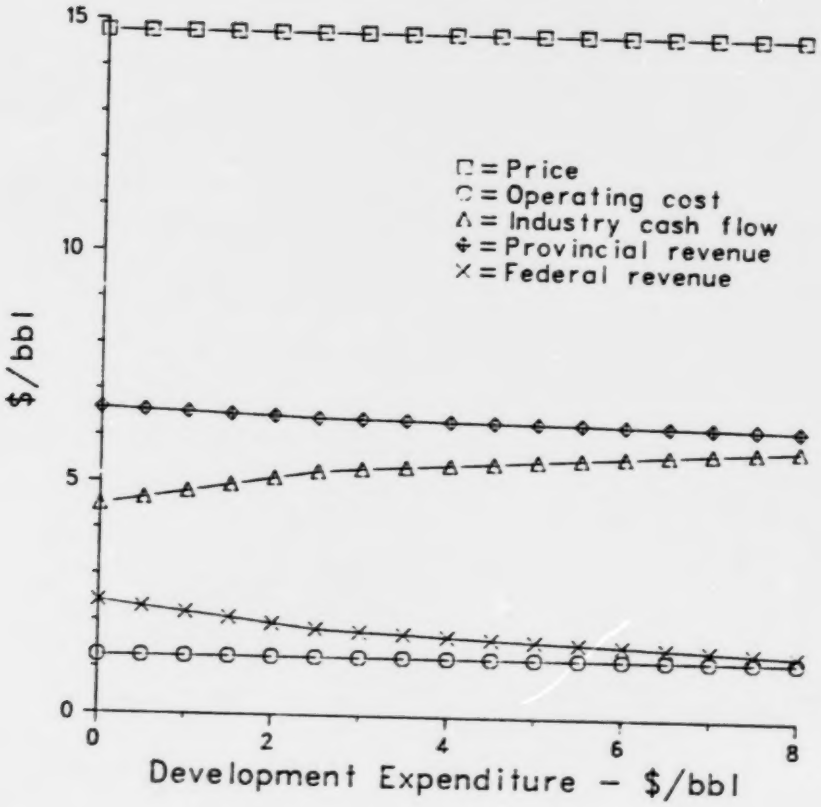
Table 3 shows how a $1.00 increase in price, operating costs, exploration and development expenditures, and a 1 percent increase in the royalty affects the distribution of revenue on the production of a current barrel of oil. Also shown is the total change in net revenue and the net expenditure by industry. The total change in net revenue is the sum of the revenue changes for the industry and Alberta and federal governments. The net expenditure by industry is after incentives offered by government.



ASSUMPTIONS

Development expenditure	=$ 1.50/bbl
Price	=$14.75/bbl
Operating costs	=$ 1.25/bbl
Lease rental	=$ .10/bbl
Capital cost allowance	=$ .10/bbl
Royalty	= 41%

FIGURE 2: Revenue Distribution of a Barrel of Oil with Varying Exploration Expenditure.



ASSUMPTIONS

Exploration expenditure	=$ 2.50/bbl
Price	=$14.75/bbl
Operating costs	=$ 1.25/bbl
Lease rental	=$ .10/bbl
Capital cost allowance	=$ .10/bbl
Royalty	= 41%

FIGURE 3: Revenue Distribution of a Barrel of Oil with Varying Development Expenditure.

TABLE 3

THE IMPACT ON CURRENT REVENUE DISTRIBUTION OF A PER UNIT INCREASE IN PRICE, OPERATING COSTS, EXPLORATION EXPENDITURE, DEVELOPMENT EXPENDITURE, AND ROYALTY ($/bbl)

	The Impact of a $1.00 Increase in:					The Impact of a 1% Increase in:
	Price	Operating Costs	Exploration Expenditure (Conventional)[a]	Exploration Expenditure (Frontier)[b]	Development Expenditure	Royalty
Industry	0.26	-0.62	0.63	0.94	0.30	-0.0089P
Alberta	0.47	-0.11	-0.15	-0.22	-0.07	0.0089P
Federal Government	0.27	-0.27	-0.48	-0.72	-0.23	no change
Total Change in Net Revenue	1.00	-1.00	0	0	0	0
Net Expenditure by Industry	n.a.	0.62	0.37	0.06	0.70	0.0089P

NOTES: The Alberta royalty rate is 41 percent which is the rate that roughly applies to 'old' oil. 'Old' oil accounts for about 95 percent of Alberta's oil production (see footnote 8). The federal tax rate is 36 percent (after Alberta rebate) and the Alberta tax rate is 11 percent (total tax rate 47 percent).
P = price of a barrel of oil.
See Appendix B for the method used in the derivation of the figures contained in this table.
n.a. = not applicable.

[a]The term 'conventional' applies to exploration and development expenditure which is eligible for 'ordinary depletion'.

[b]The term 'frontier' applies to exploration expenditure which is eligible for 'ordinary' plus 'frontier' depletion.

From the table we see that a $1.00 increase in the price of a barrel of oil is distributed $0.26 to industry, $0.47 to the Alberta government, and $0.27 to the federal government.[16]

If operating costs were assumed to increase by $1.00, industry cash flow on a barrel of oil would decline by $0.62 and government revenues would decline by $0.38 (the sum of $0.11 and $0.27). Net expenditure for the industry increases by $0.62.

A change in exploration or development expenditure does not change the net revenue on today's barrel of oil but does influence the distribution of this revenue. The change in distribution is particularly noticeable if frontier exploration is taking place. A $1.00 increase in frontier exploration earns tax incentives of $0.94 (the sum of $0.72 and $0.22). Industry frontier exploration expenditure becomes $0.06 for every $1.00 initially spent.[17]

The frontier depletion allowance of 66-2/3 percent applies to the cost of wells in excess of $5 million which is the case for most wells in the frontier. The frontier depletion is on top of ordinary depletion, meaning that for every $1.00 spent on frontier exploration, $1.00 can be immediately expensed and $1.00 can be charged to depletion, resulting in a $2.00 reduction from taxable income.

The last column of Table 3 shows how a 1 percent increase in the Alberta royalty would affect each party. Naturally, the federal revenue is unaffected; only the industry and provincial revenues are changed. The industry cash flow is reduced by 0.0089P (per barrel) and the provincial revenues are increased by the same amount.[18] At the current domestic price of $14.75, a 1 percent increase in the royalty implies a $0.13 increase in revenue to the Alberta government on each barrel of oil.

Footnotes

[1]This cost includes a return to the capital invested.

[2]Exploration expenditure essentially yields information. Development expenditure prepares a deposit for production and in doing so also yields information.

[3]See Paul G. Bradley, The Economics of Crude Petroleum Production (Amsterdam: North-Holland Publishing Company, 1967), for a discussion of such projections.

[4]If the producer was active in other provinces besides Alberta, the tax situation would be somewhat different.

[5]The CPA reports expenditures for operating, development and exploration. By dividing total expenditures in each category by total barrels produced, we arrived at the per barrel figures shown for operating, development and exploration. Total barrels, in this context, refers to barrels of crude oil equivalent. Barrels of crude oil equivalent is the aggregate of conventional crude oil and natural gas production, where natural gas is first converted to barrels of oil equivalent according to relative Btu rankings.

[6]In the September 13, 1979, Globe and Mail, it was reported that the Alberta government expects lease rentals to be about $80 million in 1979. Dividing this figure by the assumed output of 912 million barrels (oil equivalent), we arrive at close to $0.10 per barrel, as an approximation.

[7]This report was completed in July, 1979.

[8]Appendix A shows the royalty formulas for oil and natural gas. Oil and natural gas discovered before 1974 receive a higher royalty than oil and natural gas discovered since 1974. Approximately 95 percent of Alberta's production of conventional oil in 1978 consisted of old oil.

[9]The royalty is a non-neutral tax in that it decreases the revenue that the producer can earn from producing another barrel of oil and thereby lowers the incentive to expand output. A neutral tax would be a tax on the extra profit (revenue minus all costs) that can be gained from producing more oil, and as such would not lower the incentive to expand output.

[10]As a proportion of net operating revenue, i.e., price minus operating costs, these proportions become 38 percent industry, 48 percent provincial government, and 14 percent federal government.

[11]The effect of the frontier exploration allowance on the sharing of frontier exploration costs is discussed in a later part of this section.

[12]See Calgary Herald, November 12, 1979, p. B13. See footnote 10 for the distribution of net operating revenue in Alberta's conventional oil industry.

[13]See the Annual Report for the Alberta Department of Energy and Natural Resources, 1978.

[14]Without current revenue from which to expense exploration and development expenditures and apply a depletion allowance, the deductions would have to wait for future income and the present value of such deductions would be smaller than $2.00.

[15]Since our analysis concerns only the distribution of revenue from the production of a barrel of oil, other federal revenue such as that from the export tax on oil or the federal gasoline sales tax is not considered.

[16]This distribution should not be confused with the distribution of the $14.75 price shown in Table 2. Here we are showing the distribution of a $1.00 increase.

[17]The $1.00 on frontier exploration can be totally deducted from income as an exploration expense. The $1.00 can also be deducted at the rate of 100 percent (33-1/3 + 66-2/3 percent) due to the 'normal' and 'frontier' depletion allowances. Thus the firm can deduct $2.00 from taxable income. Applying the federal tax rate of 36 percent (after income tax rebate to Alberta) and the Alberta tax rate of 11 percent, the tax saving is $0.72 federal government and $0.22 Alberta government (total of $0.94). Note, however, we have not made allowance for the fact that the 'frontier' depletion only applies on per well costs in excess of $5 million. We do not believe this omission would seriously change the result.

[18]The 0.0089P can be calculated from the equation for industry cash flow (ICF) in Appendix B. Substitute R (royalty) for the 0.41 in this equation and solve for the change in ICF with respect to a change in R.

CONCLUSION

Government incentives in Canada's oil and gas industry are an integral part of the overall management of Canada's oil and gas resources. The incentives offered to the industry have changed over time reflecting new developments in domestic and world market conditions. The 1970s brought significantly higher prices for oil and gas, and the rapid depletion of conventional reserves. Both developments have stimulated new government incentives in Canada's oil and gas industry.

The main incentives offered to the industry operate through the federal income tax. The expensing provisions and the various depletion allowances are particularly important in influencing the distribution of revenue from a barrel of oil. The exact impact these and other incentives have on a company's current cash picture depend on that company's level of production, its costs, and the division of these costs between various activies.

This paper has not analyzed the impact of government incentives on industry return but rather has shown how the incentives affect the distribution of current revenue. The revenue portion that accrues to industry and the private investment expenditure necessary to generate this revenue determine the industry's return on investment.

APPENDICES

APPENDIX A

Alberta oil royalty calculation as of July 1, 1979:

$$\text{Royalty } (m^3/\text{mo.}) = S + kS\,\frac{(A-B)}{A}$$

where:

$S = \dfrac{(\text{monthly production})^2}{1{,}2711.28}$; if monthly production is less than 190.7 m^3,

or $S = \dfrac{\text{monthly production} - 190.7}{4} + 28.6$; if monthly production is greater than 190.7m^3,

$k = 1.418462$; for new oil,

or $k = 1.994962$; for old oil,

$A = \$88.48/m^3$; is par price,

and $B = \$29.64/m^3$; is select price.

NOTE: All production levels are monthly figures and are reported in volumes of cubic metres (m^3).

The federal government's Progressive Incremental Royalty (PIR) is sensitive to cost differences between pools as opposed to the standard royalty which is levied as a percentage on the selling price only. The PIR is applied to profits where allowance is made for operating costs, development costs, income taxes, and the basic royalty of 10 percent. The PIR is zero if the ratio of profit to investment is less than or equal to 25 percent. Once the ratio exceeds this level the PIR is applied at 40 percent of profits. For a complete description of the PIR see, 'Statement of Policy: Proposed Petroleum and Natural Gas Act and New Canadian Oil and Gas Land Regulations', May, 1976, Schedule D, Federal Department of Energy, Mines and Resources.

APPENDIX B

This appendix provides the basis upon which the figures in Table 3 were derived. The proceeding equations show how the federal and provincial revenues and industry cash flow from current production are determined.

Federal Revenue (F.R.):

$$F.R. = 0.36\,[P - OC - CCA - 0.25(P - OC - CCA) - E - 0.3D - 0.333(E + D)^*]$$

Provincial Revenue(P.R.):

$$P.R. = 0.41P + LR + 0.11\,[P - OC - CCA - 0.25(P - OC - CCA) - E - 0.3D - 0.333(E + D)] - 0.11\,[0.41P + LR - 0.25(P - OC - CCA)]$$

Industry Cash Flow (I.C.F.):

$$\begin{aligned} I.C.F. = {} & P - OC - 0.41P - LR \\ & - 0.36[P - OC - CCA - 0.25(P - OC - CCA)] \text{ (federal tax)} \\ & - 0.11[P - OC - CCA - 0.25(P - OC - CCA)] \text{ (provincial tax)} \\ & + 0.11\,[0.41P - LR - 0.25(P - OC - CCA)] \text{ (provincial tax rebate)} \\ & + 0.36[E + 0.3D + 0.333(E + D)] \text{ (federal tax relief)} \\ & + 0.11[E + 0.3D + 0.333(E + D)] \text{ (provincial tax relief)} \end{aligned}$$

where:
- P = price
- OC = operating costs
- CCA = capital cost allowance
- E = exploration expenditure
- D = development expenditure
- LR = lease rentals

* The term denoted (0.333(E + D) would be replaced by (0.25[P - OC - CCA - 0.25(P - OC - CCA) - E - 0.3D]) throughout if the latter was less in value.

In order to determine how the dependent variable (F.R., P.R., I.C.F.) would change with respect to a change in an independent variable (P, OC, E, D, etc.), we would take the partial derivative of the relevent equation with respect to the independent variable. The partial derivative is the incremental change in the dependent variable with respect to an incremental change in the independent variable, while holding all other variables constant.

For example, the partial derivative of federal revenue (F.R.) with respect to price (P) is denoted:

$$\frac{\partial F.R.}{\partial P} = 0.36 - 0.36(0.25) = 0.27$$

Thus a $1.00 change in P would cause a $0.27 change in F.R., all other things equal.

The results presented in Table 3 are dependent upon the current federal and Alberta tax regimes and the current Alberta royalty rates.

APPENDIX C

The following is a chronology of the more relevant changes in federal and provincial taxation and royalties affecting the oil and gas industry since 1974.

1974

i) The government of Alberta adopts the Petroleum Marketing Act establishing the Alberta Petroleum Marketing Commission designed to sell all Alberta's crown-owned oil at the highest prices possible.

ii) Alberta raises its royalty rates on natural gas as well as oil. The latter are designed to capture 65 percent of all further oil price increases.

iii) Changes announced in the Federal Budget of May 6:

- Royalties, taxes and other like payments to governments to be nondeductible for the purpose of calculating income tax;
- Development expenditure for both petroleum and mineral production to be written-off at the rate of 30 percent;
- The basic national tax rate on resource production profits to be set at 50 percent [but a special abatement of federal tax to reduce the federal rate on mineral production profits to 25 percent];
- The automatic depletion allowance is withdrawn and replaced by an 'earned' depletion of up to 25 percent of resource production profits.[1]

iv) Changes announced in the Federal Budget of November 18:

- All of the measures listed above from the May 6 budget were reintroduced;
- Exploration expenditures incurred in both mineral and petroleum production to be written-off at the rate of 100 percent;
- Profits originating from the production of oil and gas to be taxed at the federal level at 30 percent in 1974, at 28 percent in 1975, and at 25 percent in 1976.

v) The federal government unilaterally amends the existing formula for equalization payments such that only one-third of additional royalty payments originating from higher oil prices and collected by the provinces will be included in the formula.

vi) The Government of Alberta announces (in December) the Alberta Petroleum Exploration Plan whose main aspects are:

- a refund of federal tax on Alberta royalties to the oil and gas producers;
- a reduction of royalty rates for both oil and gas;
- an increase in existing exploratory drilling incentives (provincial tax credits).

vii) The government of Saskatchewan also announces measures to rebate a portion of the increased tax liabilities arising from the non-deductibility of royalties.

1975

i) Changes announced in the Federal Budget of June 23:

- Investment tax credit of 5 percent is introduced to cover all taxpayers' investment in new equipment in next two years used in the petroleum industry and elsewhere;
- The prices of oil and gas are to reach parity (on a per Btu basis) in 3 to 5 years;
- Effective in 1976, the basic corporate tax rate on resource production profits will be lowered to 46 percent (from 50 perent) which will bring the effective rate further down to 36 percent once the standard provincial abatement is applied.

ii) The government of Alberta reduces its effective royalty rate for crude oil from 65 to 50 percent on that portion of the price between $6.50 and $8.00 per barrel.

iii) The government of Saskatchewan lowers mineral taxation by 50¢/bbl of oil produced from freehold land, revises basic and premium wellhead prices by 56-64¢/bbl, and announces its intention to simplify regulations and to institute a new oil royalty which would increase producers' returns.

iv) The government of British Columbia lowers the royalty rate on oil and announces an incentive scheme whereby it will pay federal tax on deemed royalties on behalf of producers retroactive to May 6, 1974.[2]

1976

Changes announced in the Federal Budget of May 25:

- All taxpayers will immediately be able to write off 100 percent of their exploration expenses incurred between now and July 1, 1979 (the basis of the 'drilling funds');

- Capital Cost Allowance on offshore drilling platforms to be increased to 100 percent.

1977

i) Changes announced in the Federal Budget of March 31:

- The investment tax credit (5 percent) introduced in June, 1975 to be extended for 3 more years, increased to 7-1/2 and 10 percent depending on the region and the qualifying expenses to also include money spent on R & D;

- Drilling costs in excess of $5 million incurred in connection with an exploratory well in Canada (including the continental shelf) to be eligible for a further earned depletion allowance of 66-2/3 percent between now and April 1, 1980. Such drilling costs can be deducted against income by any taxpayer from any source.

ii) The Premier of Alberta announces that the province will not introduce a comprehensive oil sands and heavy oil development policy but will instead treat each new proposal 'on its own merits' as to its royalty position, possible provincial participation and incentives to be extended to industry sponsors.[3]

1978

i) Changes announced in the Federal Budget of April 10:

- Upgrading plants processing heavy oil produced from wells into a type of oil similar to conventional crude to be treated as manufacturing facilities eligible for a fast (two-year) write-off and a reduced corporate tax rate;

- The depletion allowance for enhanced recovery developments to be increased from the present 33-1/3 to 50 percent;

- The currently permitted maximum of 25 percent of an oil company income that may be plowed into non-conventional oil projects to qualify for depletion allowances to be doubled to 50 percent.

ii) Changes announced in the Federal Budget of November 16 (not passed by the Parliament prior to the May, 1979 election):

- The tax incentive for drilling funds to be extended to the end of 1981;

- Costs incurred after the date of the budget related to enhanced recovery to be included in the definition of Canadian Exploration Expense and to be eligible for earned depletion;

- The costs of clearing and removing overburden at a mine site (including oil sands plants, after it commenced production) to be written-off at a rate of 100 percent.

Footnotes

[1]The main direction of change introduced in this Budget was the non-deductibility of provincial royalties for calculating federal income tax which greatly intensified the federal-provincial dispute over oil revenues. Although to date provincial royalties have remained a non-deductible item, the issue has always been one of high contention between the industry and the provincial governments on the one hand, and Ottawa on the other.

[2]This meant that by now the three western oil producing provinces have introduced programs designed to help offset the federal ruling of 1974, which made royalty payments non-deductible for the purpose of calculating federal income tax.

[3]This announcement has created some difficulties for corporate planners since it was also made clear that at the same time the possibility of even temporarily waived royalties had not been ruled out. Subsequent developments resulted in different tax and royalty treatments for Great Canadian Oil Sands and Syncrude plants (and possibly the Alsands project as well) which violate one of the most basic principles of taxation, that taxpayers in the same postion should be treated similarly.